May 23, 2013

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge St., Suite 2700
Toronto, ON, M4P 1E4

via RESS and email

Dear Ms. Walli:

RE: Stakeholder Presentation on May 27, 2013 and May 28, 2013 Concerning Defining & Measuring Performance
Board File No.: EB-2010-0379

On May 3, 2013 the Ontario Energy Board (the "Board" or the "OEB") posted a Report prepared by Board staff's expert consultant, Dr. Lawrence Kaufmann and his team at Pacific Economics Group Research, LLC ("PEG"), that makes specific recommendations for the inflation, productivity and stretch factor parameters for incentive rate setting, and for the benchmarking of electricity distributor total costs. The Board's May 3rd letter outlined a consultation process throughout May 2013 which includes a stakeholder session to be held on May 27, 2013 and May 28, 2013, intended to give stakeholders an opportunity to present feedback on the PEG report.

Attached is the presentation for the stakeholder session from the Coalition of Large Distributors (the "CLD"). The CLD consists of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited, and Veridian Connections Inc.

The CLD appreciates the opportunity to provide further comment on the PEG report. Please contact the undersigned if you have any further questions on this submission.

Yours truly,

(Original signed on behalf of the CLD by)

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Research and Recommendations on 4th Generation Incentive Regulation

The Coalition of Large Distributors (CLD)

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- May 27 & 28, 2013

Presentation Topics

- Summary of Findings
- Discuss our research on:
  - Productivity Factor
  - Cost Benchmarking
  - Inflation Factor
- Our recommendations

Summary of Findings

- Based on our research we find:
  1. We find that a productivity factor between -0.71% to -1.32% is appropriate and substantiated by the empirical evidence
  2. The inflation factor should be industry-specific but not be subject to interest rate fluctuations during 4th Generation Incentive Regulation
  3. Cost benchmarking can be made more transparent, easier to understand, inclusive of more variables, and provide improved incentives to accomplishing Board policies of incentivizing efficiency gains and cost effectiveness
  4. Stretch factors should be solely based on the new "Unit Cost Econometric Model"

TFP Research

Outputs

- Customers
- Capacity
- Volume

Inputs

- Capital Quantity
- OM&A Quantity

PEG Dataset & TFP Work

- We applaud the efforts of PEG and the Board in constructing the historical data and the TFP indexing calculations
- We generally agree with the mechanics of PEG's TFP indexing calculations, data transformations, and assumptions

TFP Index Trend

- PEG calculated a 2002-2011 Ontario electric distribution industry TFP trend of -1.24%
  - If Hydro One and Toronto Hydro are subtracted, PEG calculated that the "restricted industry" TFP is -0.05%
- Primary motivation for subtraction appears to be the desire to have the TFP trend be external (i.e. no distributor should measurably impact its own TFP trend)

External TFP Trend Research

- We agree that an external measure is preferred
- The <u>impact of this restriction should be minimized</u> to get as close to a full industry TFP as possible

The measure should be external to each distributor but include as much of the industry as possible

- We found that if all distributors are systematically excluded one-by-one from the sample and the industry TFP (minus that one distributor) is calculated you get a TFP trend range of **-0.71%** to **-1.32%**

Table Showing External TFP Trends

*These results use all of PEG's data and calculations with the only modification being a change in the sample

Ontario External TFP Trends

	TFP Trend	min external TFP Trend	max external TFP Trend
Full Industry Sample	**-1.24%**	**-0.71%**	**-1.32%**
Full Industry Sample Excluding:	External TFP Trend		
ALGOMA POWER INC.	-1.23%		
ATIKOKAN HYDRO INC.	-1.24%		
BLUEWATER POWER DISTRIBUTION CORPORATION	-1.24%		
BRANT COUNTY POWER INC.	-1.23%		
BRANTFORD POWER INC.	-1.24%		
BURLINGTON HYDRO INC.	-1.25%		
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	-1.25%		
CANADIAN NIAGARA POWER INC.	-1.23%		
CENTRE WELLINGTON HYDRO LTD.	-1.25%		
CHAPLEAU PUBLIC UTILITIES CORPORATION	-1.24%		
COLLUS POWER CORPORATION	-1.24%		
COOPERATIVE HYDRO EMBRUN INC.	-1.24%		
E.L.K. ENERGY INC.	-1.25%		

Full Industry Sample Excluding:	External TFP Trend
ENERSOURCE HYDRO MISSISSAUGA INC.	**-1.32%**
Entegrus Powerlines	-1.24%
ENWIN UTILITIES LTD.	-1.29%
ERIE THAMES POWERLINES CORPORATION	-1.24%
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	-1.24%
ESSEX POWERLINES CORPORATION	-1.25%
FESTIVAL HYDRO INC.	-1.24%
FORT FRANCES POWER CORPORATION	-1.24%
GREATER SUDBURY HYDRO INC.	-1.25%
GRIMSBY POWER INCORPORATED	-1.24%
GUELPH HYDRO ELECTRIC SYSTEMS INC.	-1.25%
HALDIMAND COUNTY HYDRO INC.	-1.24%
HALTON HILLS HYDRO INC.	-1.26%
HEARST POWER DISTRIBUTION COMPANY LIMITED	-1.24%
HORIZON UTILITIES CORPORATION	-1.26%
HYDRO 2000 INC.	-1.24%
HYDRO HAWKESBURY INC.	-1.24%
HYDRO ONE BRAMPTON NETWORKS INC.	-1.31%
HYDRO ONE NETWORKS INC.	**-0.71%**
HYDRO OTTAWA LIMITED	-1.28%
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	-1.24%
KENORA HYDRO ELECTRIC CORPORATION LTD.	-1.24%
KINGSTON HYDRO CORPORATION	-1.24%
KITCHENER-WILMOT HYDRO INC.	-1.26%
LAKEFRONT UTILITIES INC.	-1.24%
LAKELAND POWER DISTRIBUTION LTD.	-1.24%
LONDON HYDRO INC.	-1.26%
MIDLAND POWER UTILITY CORPORATION	-1.24%
MILTON HYDRO DISTRIBUTION INC.	-1.26%
NEWMARKET-TAY POWER DISTRIBUTION LTD.	-1.25%

Lowest external productivity factor

Highest external productivity factor

Full Industry Sample Excluding:	External TFP Trend
NIAGARA PENINSULA ENERGY INC.	-1.25%
NIAGARA-ON-THE-LAKE HYDRO INC.	-1.24%
NORFOLK POWER DISTRIBUTION INC.	-1.25%
NORTH BAY HYDRO DISTRIBUTION LIMITED	-1.24%
NORTHERN ONTARIO WIRES INC.	-1.24%
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	-1.26%
ORANGEVILLE HYDRO LIMITED	-1.24%
ORILLIA POWER DISTRIBUTION CORPORATION	-1.24%
OSHAWA PUC NETWORKS INC.	-1.25%
OTTAWA RIVER POWER CORPORATION	-1.24%
PARRY SOUND POWER CORPORATION	-1.24%
PETERBOROUGH DISTRIBUTION INCORPORATED	-1.25%
POWERSTREAM INC.	-1.28%
PUC DISTRIBUTION INC.	-1.24%
RENFREW HYDRO INC.	-1.24%
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	-1.24%
SIOUX LOOKOUT HYDRO INC.	-1.24%
ST. THOMAS ENERGY INC.	-1.24%
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	-1.25%
TILLSONBURG HYDRO INC.	-1.24%
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	-0.95%
VERIDIAN CONNECTIONS INC.	-1.28%
WASAGA DISTRIBUTION INC.	-1.24%
WATERLOO NORTH HYDRO INC.	-1.25%
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	-1.24%
WELLINGTON NORTH POWER INC.	-1.24%
WEST COAST HURON ENERGY INC.	-1.24%
WESTARIO POWER INC.	-1.24%
WHITBY HYDRO ELECTRIC CORPORATION	-1.26%
WOODSTOCK HYDRO SERVICES INC.	-1.24%

Productivity Factor Implications

- An external measure that includes substantially more industry data than PEG's measure leads to a TFP range of -0.71% to -1.32%.

TFP Indexing Summary

Sample	% of Industry Retail Customers Included	External Measure?	2002-2011 TFP Trend
Full Industry	100.0%	Essentially, except for HONI & THESL	-1.24%
Excluding HONI & THESL	60.3%	Essentially	-0.05%
Systematically exclude one distributor at a time	**75.0% to 99.98%**	**Yes**	**-0.71% to -1.32%**

Econometric TFP Projections

- PEG's productivity factor recommendation of zero is partially supported by its econometric TFP projection of -0.03% (Table 20 in the PEG Report)
- We believe the calculations used in determining the result, in particular the cost projections found on Table 19 which lead to the TFP result in Table 20, are inconsistent with PEG's model and cost theory
- Corrected cost projections lead to a -0.97% econometric TFP projection

Overview of Table 19

- Table 19 feeds into Table 20 which is PEG's econometric TFP projection
  - We agree with Table 20
  - We believe Table 19 is inconsistent with PEG's model, economic theory, and PEG's prior practices

Key Issue: PEG's Table 19 omits the OM&A input price variable and inflation leading to a TFP projection of -0.03%

- OM&A price inflation could have been zero, 10%, or 100% and PEG Table 19 would show the exact same cost projection
  - Average growth rate in OM&A input price was 2.30% (cost share of 41% * 2.30% = 0.94% of projected cost growth not accounted for)

Tests to Substantiate a Corrected Table 19

- PEG cost projection growth rate = 2.73% (implying a TFP projection of -0.03%)
- PSE cost projection growth rate = 3.67% (implying a TFP projection of -0.97%)
  - Difference of 0.94%

- **Test 1**: Actual cost growth from 2002 to 2011 in benchmarking dataset is **3.74%**
- **Test 2**: PEG's 2007 method results
- **Test 3**: PEG's 2007 method results with business conditions
- **Test 4**: Growth rate in average cost benchmark in 2002 to average cost benchmark in 2011

Test 2 & 3: PEG's 2007 TFP Projection Method

- A 2007 PEG Report for the Board in regards to Gas Distribution IR used a different set of calculations to estimate an econometric TFP
  - Tested and reviewed by the Board
- If we insert the 2013 model coefficients and 2002-2011 electric industry variable growth rates into PEG's exact 2007 methodology we get an econometric TFP projection of **-0.85%**
- The 2007 econometric TFP projection method was also peer reviewed and published in the Journal of Network Economics in 2009
  - Co-authored by Dr. Mark Lowry (President of PEG) and Dr. Lullit Getachew (Senior Economist at PSE)

Test 2 & 3: PEG's 2007 Method Result

	2002-2011 (Table 12 Model of 2013 Report)
Elasticity Estimates from PEG-R cost model	
Customers [A]	0.295
System Capacity [B]	0.366
Total Deliveries [C]	0.093
Output Index Weights from PEG-R cost model	
Customers [D]	39.1%
System Capacity [E]	48.5%
Total Deliveries [F]	12.3%
Subindex Growth based on PEG-R Report	
Customers [G]	1.61%
System Capacity [H]	0.95%
Total Deliveries [I]	0.93%
Sum of Output Elasticities [J = A+B+C]	0.754
Output Growth (elasticity weighted from PEG-R Report) [K=D*G+E*H+F*I]	1.21%
Technology Change [L]	-1.15%
Returns to Scale [M=(1-J)*K]	0.30%
TFP Projection "2007 PEG Method" [L+M]	**-0.85%**

PEG's 2007 method produces an econometric TFP estimate of -0.85%.

The 2013 PEG Report also included business condition variables. If the 2007 method is modified to also include the business condition variables the TFP projection equals -0.93%.

Test 4: Alternative Econometric TFP Projection

- PSE averaged all of the 2002 explanatory values in PEG's 2013 model
  - Produced a cost prediction of $37.1M
- PSE then averaged all of the 2011 explanatory values
  - Produced a cost prediction of $51.4M
- This is an econometric cost projection growth rate of 3.63%
  - **If inserted into Table 20 it implies a TFP projection of -0.93%**
  - Substantiates PSE's Table 19 method & PEG's 2007 Method

Summary of Cost & TFP Projections

Method	2002-2011 Average Annual Cost Growth	Implied TFP trend
PEG's Table 19 2002-2011 Cost Projection **or** **PSE's Revised Table 19 2002-2011 Cost Projection**	**2.73%** **or** **3.67%**	**-0.03%** **or** **-0.97%**
Test 1: PEG's Benchmarking Dataset's Actual Cost Growth from 2002-2011	3.74%	-1.04%
Test 2: PEG's 2007 TFP Projection Method	N/A	-0.85%
Test 3: PEG's 2007 TFP Projection Method with Business Condition Variables	N/A	-0.93%
Test 4: 2002 Average Econometric Model Prediction to 2011 Average Econometric Model Prediction	3.63%	-0.93%

Inflation Factor Research

Inflation Factor

- Customers and distributor planning are harmed when prices/revenues are unpredictable & volatile
- PEG's "Three Factor" recommendation showed some volatility relative to the 3GIR factor

Year	GDP-IPI	PEG "Three Factor" Annual	3-Year Moving Average
2006	1.90%	0.12%	0.97%
2007	2.10%	2.68%	1.52%
2008	2.30%	2.36%	1.72%
2009	1.30%	1.24%	2.09%
2010	1.30%	2.44%	2.01%
2011	2.00%	0.70%	1.46%
2012	1.60%	-1.62%	0.51%

Why the Volatility?

- Annual cost of capital changes are in PEG's capital service price index
  - These tend to fluctuate and could also be leading to double-counting
- President of PEG, Dr. Mark Lowry, testified last year during the Alberta PBR initiative,

"I have never seen a plan involving an index that also involves an adjustment for financing rate changes. You would think that the – there is a danger of double-counting of that since [if] there is a change in interest rates eventually it will have an effect on general inflation rates." (Transcript, Volume 14, pages 2660, line 18 to page2661, line 2)

What Did PEG Propose in Alberta?

- Proposed on behalf of the Consumers Coalition of Alberta (CCA)
- "Three Factor" Index
  - Alberta GDP-IPI (**non-labour component**)
  - Alberta Average Weekly Earnings (**labour component**)
  - Change in the Triangulized Weighted Average (TWA) in the Electric Utility Construction Price Index (EUCPI) (**capital component**)

Alternative Inflation Factor

- We recommend using the same inflation factor approach as PEG proposed in Alberta
  - Using the analogous Ontario or Canadian indexes rather than the Alberta ones
- Only difference relative to current PEG recommendation is the capital component
  - TWA price is a weighted average of the historical asset prices that distributors pay to procure capital
    - Essentially, a weighted average of the prices paid for assets now in the rate base
    - Does not include cost of capital changes

Why This Inflation Factor is Better

1. It is an industry-specific inflation measure (RRFE requires an industry-specific measure)
2. Far less volatility than the current PEG recommendation
3. Avoids the potential of double-counting interest rate and inflation changes
4. Simpler calculation than the PEG capital service price
   - Interest rate volatility can work in both directions… Distribution planners and customers are better off with gradual and more stable rate changes

What Exactly is a Triangulized Weighted Average of the EUCPI?

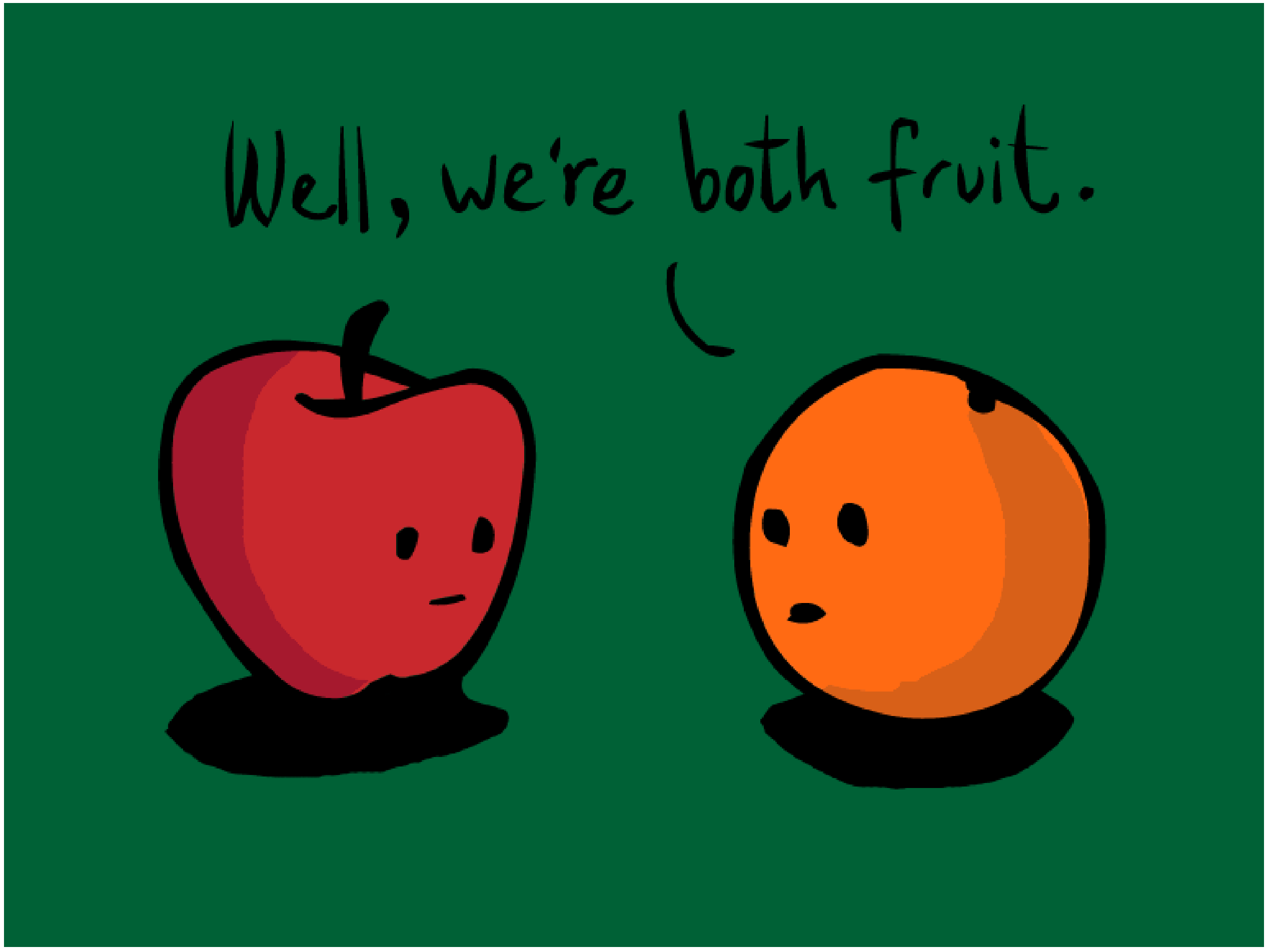
Year	EUCPI Value [A]	Straight-line Asset Left in Year T [B]	Weight [C=B/Sum(B)]	Weight*EUCPI [D=C*A]	Sum to Get Capital Index [Sum(D)]
T-40	24.1	1/40	0.12%	0.03	
T-20	98.5	20/40	2.44%	2.40	
T-4	142.4	36/40	4.39%	6.25	
T-3	148.8	37/40	4.51%	6.71	
T-2	150.3	38/40	4.63%	6.96	
T-1	151.1	39/40	4.76%	7.19	
T (current year)	155.1	40/40	4.88%	7.57	
Sum		**20.5**			**115.9 in 2010**

Measures the weighted average price of capital assets purchased through time

Summary of Inflation Factors

Year	GDP-IPI (3GIR)	PEG "Three Factor" 3-Year Moving Average	"Three Factor" with TWA Annual
2006	1.90%	0.97%	2.51%
2007	2.10%	1.52%	3.13%
2008	2.30%	1.72%	2.72%
2009	1.30%	2.09%	2.22%
2010	1.30%	2.01%	2.88%
2011	2.00%	1.46%	2.32%
2012	1.60%	0.51%	N/A
Standard Deviation	**0.39%**	**0.56%**	**0.35%**

Moving to Cost Benchmarking



Cost Benchmarking

- We have developed a benchmarking framework that we feel accomplishes six things:
  1. Is far easier to understand and explain
  2. Is neutral to, rather than disincentivizing, distributors for the efficiency gains of increasing in size
     - That is, cost efficiency gains from larger size are incorporated in the benchmarking ranking, not pre-judged by the model
  3. Increased efficiency incentives by making it easier to move from one stretch factor to another
  4. Provide key information to managers about their cost levels and how high or low they are in actual dollar terms
  5. Increase the number of business conditions in the model so it's a more accurate and a fairer depiction of performance (also is much "tighter" in its results)
  6. Eliminates the need for a second approach

Our Recommended Approach

- We essentially combined the unit cost indexing approach and the econometric approach into one benchmarking framework
  - **Unit Cost Econometric Model**
- We felt PEG did a commendable job in putting together the cost data and variables
- We also felt the effort in putting together the historical (pre 2002) data is extremely helpful
  - For this reason we used PEG's exact cost benchmarking definitions and data transformations in our model
  - We included additional business condition variables into the model

Unit Cost Econometric Model

- Cost per customer is explained by:
  - KM of Line per customer
  - Peak capacity per customer
  - Area per customer
  - Customer growth
  - **Wind variable**
  - **Load Factor**
  - **Distribution transformers per customer**
  - **Percent single-phase lines**
  - **Age (Acc. Dep./Gross Plant)**
  - **Age Squared**
  - Time Trend

* New Variables are bolded

Variables we didn't have time to gather & test but we think may further improve the model:

- % Embedded kW or kWh
- Forestation Variable using GIS
- Urban Core

Math We Can Understand

- No natural logs, no interaction terms, no quadratic terms, just the variables and their impact on cost per customer (all in dollar terms)
- Regression fills in the “a” parameters
- Each parameter tells us how much an increase of “1” in the variable will change the unit cost
  - So if the ratio of peak to customers goes up by one then the cost per customer is estimated to increase by the value of a2

$$\frac{C}{N} = a1 + a2 * \frac{Peak}{N} * Trend + a3 * \frac{KM}{N} + a4 * \frac{Area}{N} + a5 * \%UG + a6 * LF + a7 * \frac{D\ Trans}{N} + a8 * Wind + a9$$

Preliminary Unit Cost Econometric Model

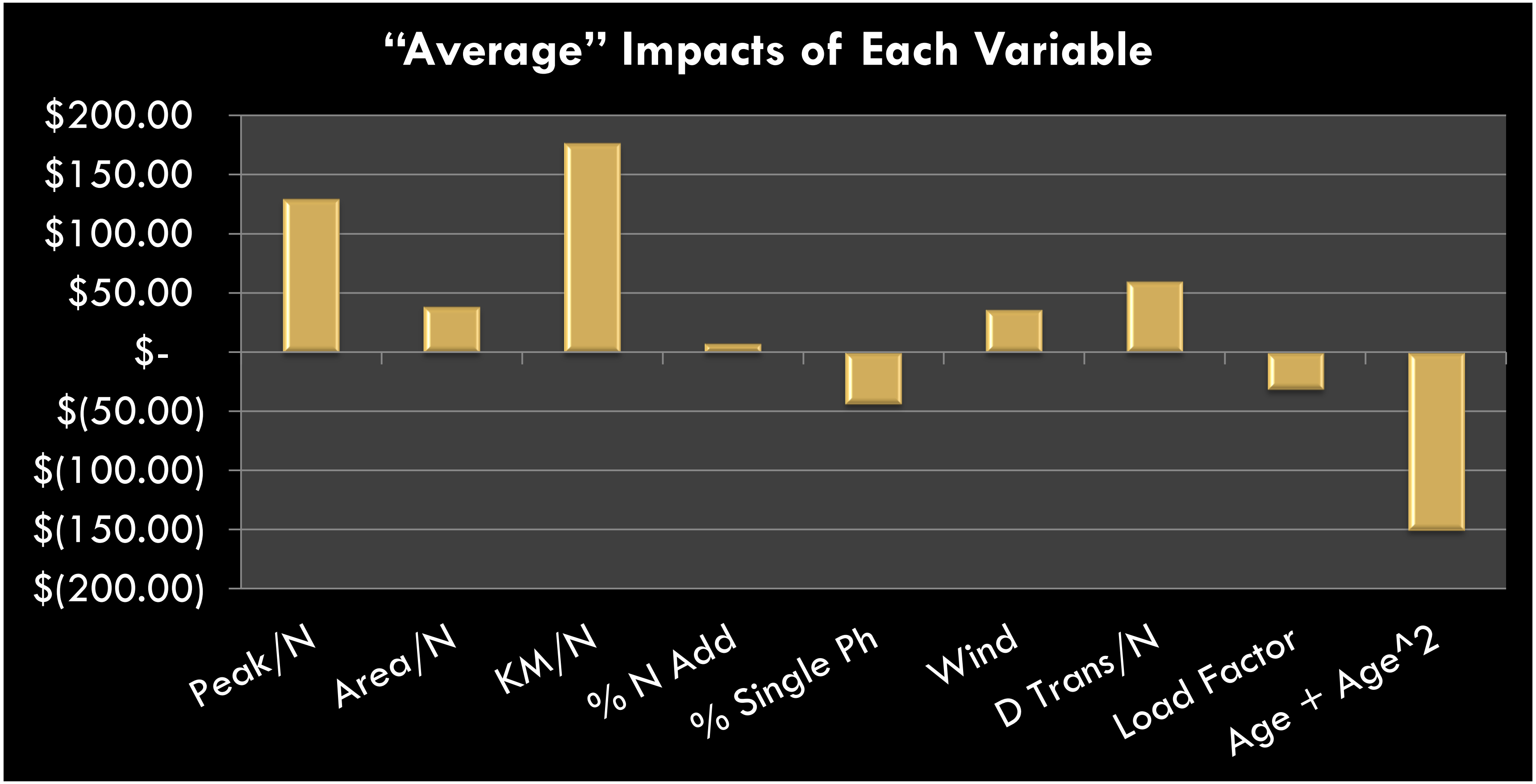
Variable	Coefficient	T-Statistic
KM of Line/N	3043.21	11.25
Capacity/N	29.53	22.11
Area/N	370.41	9.25
Customer Growth	47.89	6.75
Wind	4.07	18.53
Load Factor	-52.90	-3.77
D Trans/N	277.19	3.72
% Single Phase	-89.37	-4.39
Age (Acc Dep/Gross Plant)	-829.78	-5.79
Age Squared	1065.09	6.51
Time Trend	5.93	4.68
Constant	439.18	11.53

Coefficients show how much cost per customer is predicted to go up if variable increases by "1"

*All variables are statistically significant at a 99% confidence level

Impacts on Unit Cost of Each Variable for the "Average" of Each Variable

Impacts will vary based on distributor values. For example, a utility with double the average of area per customer will have twice the impact on unit costs from that variable.



Improved Range of Scores

- Unit Cost Econometric Model range of 2009-2011 average scores is -31.7% to 42.0%
- PEG model's 2009-2011 range of average scores is -64.4% to 69.2%

- Distributors who find cost efficiencies will be able to move more easily with the Unit Cost Econometric Model

Incentives for Efficiency Gains

- We feel our model better aligns itself with the Board's objective of promoting economic efficiency and cost effectiveness within the distribution industry
- Example: Assume two "average" distributors decide to merge
- **PSE's Unit Cost Econometric Model**
  - Pre-merger: 2011 Unit cost benchmark for each distributor equals $723.19
  - Post-merger: Unit cost benchmark will still equal $723.19 for the new distributor
    - ⇒ **Benchmark stays the same for the merged utility (any efficiency gains from merger will be reflected in an improved benchmarking rank)**

Incentives for Efficiency Gains

- <u>Example</u>: Assume two "average" distributors decide to merge
- **PEG Econometric Model**
  - Pre-merger: 2011 Total cost benchmark for each distributor equals \$51.4M
  - Post-merger: Total cost benchmark equals \$88.6M
    - ⇒ **PEG Model "takes away" \$14.2M in efficiency gains (\$51.4M+\$51.4M - \$88.6M)**
    - **Merged utility held to a far more difficult standard**
      - Model "pre-judges" efficiency gains
      - In this example, if the utility only finds \$10M in efficiency gains its benchmarking rank will actually decline
- We believe the PEG model provides disincentives for distributors to uncover efficiency gains through mergers
- Unit Cost Econometric Model is neutral in this regard and assigns any efficiency gains to an improved benchmarking score

Preliminary Top 5 Results Example

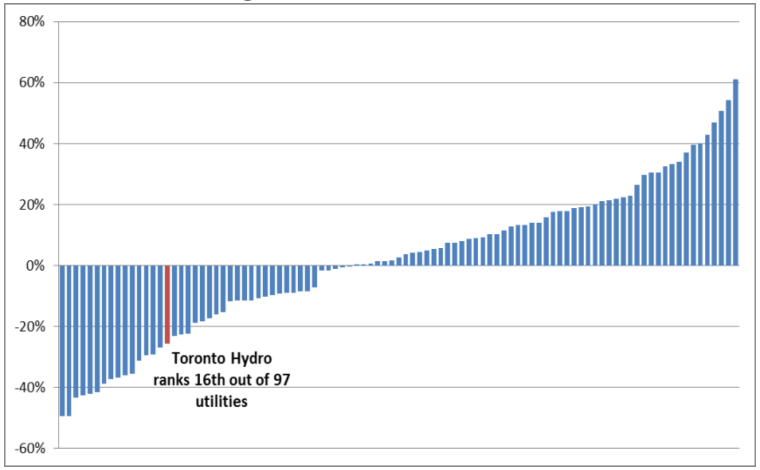
Distributor	Unit Cost Benchmark	Unit Cost Actual	Unit Cost Difference	% Difference
Welland Hydro	$573.65	$417.92	-$155.73	-31.7%
Oshawa PUC	$560.01	$420.40	-$139.60	-28.7%
Kitchener-Wilmot Hydro	$539.12	$405.47	-$133.66	-28.5%
Horizon Utilities	$546.91	$417.73	-$129.18	-26.9%
Haldimand County Hydro	$831.25	$651.77	-$179.48	-24.3%

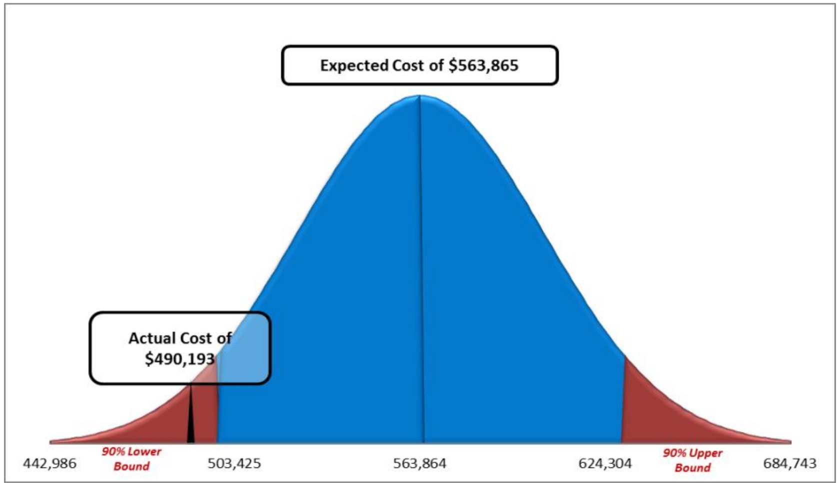
One Caveat

- Unit Cost Econometric Model cannot account for the known cost challenges of serving an urban core
  - Toronto is the only city in the Province large enough to constitute a large urban core
- Benchmark findings from this Ontario-only model are not accurate for Toronto Hydro

Toronto Hydro Solution

- <u>Possible Toronto Hydro Solution</u>
  - Use a U.S. model with an urban core variable to evaluate Toronto Hydro
  - In a prior study for Toronto Hydro we found the company's average 2009-2011 total costs to be 14% below the model's benchmark and statistically significant at a 90% confidence level





Recommendations

Recommendations on Productivity Factor

- Empirical evidence (industry TFP indexing & econometric TFP estimates) point to a 2002-2011 industry-wide productivity factor in the ballpark of -1.00%
- TFP is slowing even more in recent years
  - De-industrialization, CDM, Smart Meters, aging infrastructure, FIT, etc…
- External TFP trends ranged from -0.71% to -1.32% with a full industry TFP trend of -1.24%

On the basis of the calculated external TFP trends, we recommend a productivity factor in the range of -0.71% to -1.32%

Recommendation on Inflation Factor

- Using the TWA of the EUCPI will likely be less volatile, more transparent, and doesn't double-count interest rates and input price inflation
- It accomplishes the objectives of being industry-specific, stable, and reflective of the historical asset costs in the industry

For these reasons, we recommend using PEG's recommended approach in Alberta of a TWA of the EUCPI combined with the Ontario AWE and the Ontario (or Canadian) GDP-IPI

Recommendations on Cost Benchmarking

- Unit Cost Econometric Model is more intuitive, simpler, includes more explanatory variables, rewards efficiency gains, and has a “tighter” range
  - It combines the unit cost indexing approach with the econometric approach (mix of large and small distributors in the top and bottom)

For these reasons, we recommend using the Unit Cost Econometric Model as the sole evaluation of distributor stretch factors

Recommendation on Stretch Factors

- Stakeholders will benefit by increasing the ability (and incentives) of distributors moving from one stretch factor to another
  - Unit Cost Econometric Model can be used to calculate stretch factors
    - Eliminating the unit cost indexing approach will substantially increase the ability of distributors to move from one stretch factor to another
    - Tighter range of the Unit Cost Econometric Model means that it will be easier for distributors to move relative to the PEG econometric model and PEG peer groups

I recommend that stretch factors be set at “0” for the top distributors and progressively move to a maximum stretch factor of 0.5% based on six cohort groups derived from the Unit Cost Econometric Model rankings

Could You Further Explain that Stretch Factor Recommendation?

Stretch factors between 0 to 0.50% align with what is seen in other incentive regulation plans.

Rank (Last 3 years)	Stretch Factor
#1 to #12	0.00%
#13 to #24	0.10%
#25 to #36	0.20%
#37 to #48	0.30%
#49 to #60	0.40%
#61 to #73	0.50%

Summary of Recommendations

4th Generation IR Component	My Recommendation
Productivity Factor	-0.71% to -1.32%
Inflation Factor	“Three Factor” using TWA of EUCPI
Cost Benchmarking	Use the Unit Cost Econometric Model
Stretch Factors	Six groups based on ranks from the Unit Cost Econometric Model, start at 0.00% and increase by 0.10% for each group

Thank You! Questions?

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the **power** to help you succeed.

Appendix


CASIO
fx-85WA
S-V.P.A.M.
TWO WAY POWER
1337
SHIFT
ALPHA
REPLAY
MODE
ON
nCr
Pol(
log
ln
ENG
hyp
sin
cos
tan
STO
RCL
M+
DEL
AC
EXP
Ans

Brief Summary of Econometric TFP Projections

Step 1: Insert the econometric model coefficients into Table 19

Step 2: Insert the 2002-2011 annual % change in the variables that are estimated in the model

Step 3: Multiply the coefficients with the % change in the variables

Step 4: Sum the products in Step 3 and add the trend variable which leads to the 2002-2011 growth rate in the model's dependent variable (which is cost/wOM&A)

Step 5: Add the OM&A input price inflation to estimate the econometric cost projection

$$\ln\left(\frac{Cost}{wOM\&A}\right) = a1 + a2 * \ln(Customers) + a3 * \ln\left(\frac{wK}{wOM\&A}\right) + \ \ldots$$

Step 1 & Step 2

- Step 1 in Table 19 is done how we would do it
- Step 2 is done how we would do it, except for the capital input price % change (term [T] on Table 19)
  - Variable for the capital input price is actually defined in PEG's model as (wK/wOM&A)
- Term [T] should be the growth in the actual variable estimated in the model (wK/wOM&A) not the growth rate in WK.
  - Term [T], in our opinion, should be -1.29% not the 1.01% inserted in Table 19
    - Derived from growth rate in wK (1.01%) minus growth rate in wOM&A (2.30%)

$$\ln\left(\frac{Cost}{wOM\&A}\right) = a1 + a2 * \ln(Customers) + a3 * \ln\left(\frac{wK}{wOM\&A}\right) + \;\ldots$$

Where In the World Are We At?

- Suggested Table 19 Change

Subindex Growth	PEG Table 19	PSE Change	Comments
Customers [M]	1.61%	No change	
System Capacity [N]	0.95%	No change	
Total Deliveries [O]	0.93%	No change	
Service Territory Size [P]	0.00%	No change	
% of Lines Underground [Q]	1.93%	No change	
Average Line Length [R]	0.00%	No change	
Customer Additions [S]	0.00%	No change	
Capital Input Price [T]	1.01%	-1.29%	Actual Variable in the Model is wk/wOM&A. The variable grew by -1.29% from 2002-2011. (1.01% - 2.30%)

Step 3 & 4

- Steps 3 & 4 are done correctly, in our opinion, except for the modification mentioned in Step 2.
- This will produce the expected growth rate in the model's dependent variable which is, again, cost divided by the OM&A input price.

$$\ln\left(\frac{Cost}{wOM\&A}\right) = a1 + a2 * \ln(Customers) + a3 * \ln\left(\frac{wK}{wOM\&A}\right) + \ \dots$$

Step 5

- Table 19 does not account for the fact that the dependent variable is cost divided by the OM&A input price (cost/wOM&A)
  - Along with the missing part of Step 2 this leads to Table 19 ignoring the OM&A input price inflation

Hide the Calculators!

- Mathematically, the impact on cost should be the OM&A cost share (41%) multiplied by the growth rate (2.30%)
- $\Delta\left(\frac{C}{\boldsymbol{wOM\&A}}\right) = 0.59 * \Delta\left(\frac{\boldsymbol{wK}}{\boldsymbol{wOM\&A}}\right)$ + other "stuff" we agree with
- $\Delta C\ - \Delta wOM\&A = 0.59 * \Delta(wK/wOM\&A)$ + "Stuff"
- $\Delta C\ - \Delta wOM\&A = 0.59 * \Delta wK - 0.59 * \Delta wOM\&A$
- $\boldsymbol{\Delta C = 0.59 * \Delta wK + 0.41 * \Delta wOM\&A + "Stuff"}$
  - Notice that 0.59 + 0.41 = 1.00 (Table 19 needs to show that a 1% increase in all input prices leads to a 1% increase in total costs)
- ~0.94% of projected cost growth is being ignored in PEG's Table 19

$$\ln\left(\frac{Cost}{wOM\&A}\right) = a1 + a2 * \ln(Customers) + a3 * \ln\left(\frac{wK}{wOM\&A}\right) + \ \ldots$$

PSE Revised Table 19

Econometric Coefficient Estimates	Industry Average 2002-2011
Customers [A]	0.29
System Capacity [B]	0.37
Total Deliveries [C]	0.09
Service Territory Size [D]	0.07
Percentage of Lines Underground [E]	0.04
Average Line Length [F]	0.09
Customer Additions in Previous 10 Years [G]	0.04
Capital Input Price/OM&A Input Price [H]	0.59
Subindex Growth	
Customers [M]	1.61%
System Capacity [N]	0.95%
Total Deliveries [O]	0.93%
Service Territory Size [P]	0.00%
Percentage of Lines Underground [Q]	1.93%
Average Line Length [R]	0.00%
Customer Additions in Previous 10 Years [S]	0.00%
Capital Input Price/OM&A Input Price [T]	-1.29%
Subindex Growth*Econometric Coefficients	
Customers [U=A*M]	0.47%
System Capacity [V=B*N]	0.35%
Total Deliveries [W=C*O]	0.08%
Service Territory Size [X=D*P]	0.00%
Percentage of Lines Underground [Y=E*Q]	0.08%
Average Line Length [Z=F*R]	0.00%
Customer Additions in Previous 10 Years [AA=G*S]	0.00%
Capital Input Price/OM&A Input Price [BB=H*T]	-0.76%
Trend [CC]	1.15%
Change in Projected Cost/wOM&A [DD=U+V+W+X+Y+Z+AA+BB+CC]	1.37%
Change in Projected Cost [DD+OM&A Input Price Inflation of 2.30%	**3.67%**

PSE projected cost growth methodology shows cost growth 0.94% higher than PEG's. This is equal to the cost share of OM&A (41%) multiplied by the growth rate of OM&A of 2.30%.

If new result is inserted into PEG's Table 20 the econometric TFP projection is -0.97%.